ORIGINAL

0000177072

BEFORE THE ARIZONA CORPORATION COMMISSION

AZ CORP COMMISSION
DOCKET CONTROL

2017 FEB -3 P 1:42

**COMMISSIONERS**

TOM FORESE – Chairman
BOB BURNS
DOUG LITTLE
ANDY TOBIN
BOYD DUNN

Arizona Corporation Commission
DOCKETED
FEB 3 2017
DOCKETED BY

| | |
|---|---|
| IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN. | DOCKET NO. E-01345A-16-0036 |
| IN THE MATTER OF FUEL AND PURCHASED POWER PROCUREMENT AUDITS FOR ARIZONA PUBLIC SERVICE COMPANY. | DOCKET NO. E-01345A-16-0123 |

**ARIZONA INVESTMENT COUNCIL'S NOTICE OF FILING**

Arizona Investment Council ("AIC") hereby provides notice of filing the Direct Rate Design Testimony of Gary Yaquinto, Branko Terzic and Daniel G. Hansen in the above-referenced matter.

RESPECTFULLY SUBMITTED this 3rd day of February, 2017.

OSBORN MALEDON, P.A.

By: Meghan H. Grabel

Meghan H. Grabel
2929 N. Central Avenue, Suite 2100
Phoenix, AZ 85012

Attorneys for Arizona Investment Council

**Original and 13 copies** filed this
3rd day of February, 2017, with:

Docket Control
Arizona Corporation Commission
1200 West Washington Street
Phoenix, AZ 85007

**Copies** of the foregoing mailed
this 3rd day of February, 2017, to:

All Parties of Record

Patricia D. Palmer

6980335

# BEFORE THE ARIZONA CORPORATION COMMISSION

**COMMISSIONERS**

TOM FORESE – Chairman
BOB BURNS
DOUG LITTLE
ANDY TOBIN
BOYD DUNN

| | |
|---|---|
| IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN. | DOCKET NO. E-01345A-16-0036 |
| IN THE MATTER OF FUEL AND PURCHASED POWER PROCUREMENT AUDITS FOR ARIZONA PUBLIC SERVICE COMPANY. | DOCKET NO. E-01345A-16-0123 |

Direct Rate Design Testimony of

**Gary Yaquinto**

On Behalf Of

Arizona Investment Council

February 3, 2017

OSBORN MALEDON
A PROFESSIONAL ASSOCIATION
ATTORNEYS AT LAW

## I. QUALIFICATIONS

**Q: Please state your name, position and business address.**

A: Gary M. Yaquinto. I am the President and CEO of Arizona Investment Council ("AIC"). Our offices are located at 2100 North Central Avenue, Phoenix, Arizona 85004.

**Q. Please summarize your educational background and professional experience.**

A: I earned B.S. and M.S. Degrees in Economics in 1974 from Arizona State University, as well as an MBA from the University of Phoenix in 2005. From 1975 to 1977, I was employed by the State of Wyoming as an economist responsible for evaluating the economic, fiscal and demographic effects of resource development in Wyoming. From 1977 to 1980, I was Chief Research Economist for the Arizona House of Representatives. From 1980 to 1984, I was employed as an economist in the consulting industry. Since 1984, I have worked in various capacities in government and the private sector in the areas of utility regulation and government affairs. I held positions of Assistant Director and Director with the ACC Utilities Division from 1984 to 1997. Following my positions with the ACC, I was employed as Vice President of Government and Regulatory Affairs for a competitive local exchange telephone carrier and as a consultant. I also served as the Chief Economist at the Arizona Attorney General's Office from 2003-2005 and as the Director of the Governor's Office of Strategic Planning and Budgeting from 2005-2006. I became AIC's President in December 2006.

## II. ARIZONA INVESTMENT COUNCIL ("AIC")

**Q. What is the Arizona Investment Council and what is its mission?**

A: AIC is a non-profit association organized under Chapter 501(c)(6) of the Internal Revenue Code. AIC's membership includes approximately 6,000 individuals—many of whom are debt and equity investors in Arizona utility companies and other Arizona businesses.

AIC's mission is to advocate on behalf of its members' interests, primarily before regulatory bodies, as well as at the Legislature, specifically to enlarge and maximize the influence of utility investors on public policies and governmental actions that impact investors and their investments.

AIC also works with the Commission and policymakers generally to support investment in Arizona's essential backbone infrastructure, as well as improvements to or remediation of existing facilities. We view this aspect of our mission as complementary to our core advocacy of investor interests. Continuing investment in essential, backbone infrastructure is the foundation in support of a well-functioning and robust economy.

## III. EXPERIMENTAL ALTERNATIVE GENERATION RATE RIDER TESTIMONY

**Q: What is the purpose of your testimony?**

A: The purpose of my testimony is to oppose renewal of APS's Alternative Generation tariff, "AG-1".

APS's experimental program has resulted in unrecovered costs being shouldered by the Company and its shareholders since the program was implemented in 2012. Although the Settlement Agreement that implemented

AG-1 allowed APS to share in off-system wholesale margins, the program has failed to fully recover its costs in an amount that exceeds $34 million as of September 2016.[1] Even though the Company has been allowed to defer some costs incurred since July 1, 2016 for potential recovery in this case, the losses continue to build.

Whether the losses are borne by the Company and its shareholders, or deferred for later recovery from other customers, the bottom line is that someone other than the few large commercial and industrial customers that have benefited from AG-1 over the last five plus years, will be paying for the program.

**Q: Please describe the AG-1 experimental program.**

A: The AG-1 experimental rate was part of APS's 2012 Rate Case Settlement Agreement, approved by the Commission in Decision No. 73183 (May 24, 2012). The AG-1 experimental rate is a "buy through" arrangement, which allows certain large and extra-large commercial and industrial customers to arrange to purchase power from an alternative generation provider. APS takes title to the power from the alternative provider, and delivers it through its own transmission and distribution system to the customer. The original experiment is capped at 200 MW and was intended to expire after four years. Additionally, APS was allowed to mitigate potential lost margins on generation service by sharing in margins derived from wholesale sales, which otherwise would be credited to the PSA.

---

[1] See Exhibit GMY-1DR: APS's response to AIC data request 1.1, December 28, 2016. This reflects the net impact of the program after accounting for the margin mitigation amounts from wholesale margins.

In implementing the AG-1 rate, APS received applications from potential participants, whose applications in total exceeded the 200 MW cap. APS conducted a lottery among the applicants and eight customer participants were selected to participate in the program. The eight participants currently taking AG-1 service are Wal-Mart, Honeywell, Safeway, Home Depot, City of Phoenix, Marriott, Freeport McMoRan, and Kroger.[2]

Although the AG-1 experimental program was intended to expire on July 1, 2016 in conjunction with the anticipated conclusion of APS's next rate case, the program was extended by the Commission in Decision No. 75322 (November 25, 2016) to coincide with the conclusion of this rate case. Also in Decision No. 75322, the Commission authorized APS to defer 90 percent of the first $10 million and 100 percent after the first $10 million of unrecovered unmitigated costs annually, beginning July 1, 2016.

In the current rate case application, APS proposes to include $8.6 million of deferred costs in rate base. $8.6 million equates to a revenue requirement increase of $3.8 million to be recovered over 5 years from non-residential and street and area lighting customers.[3]

Finally, both the Settlement Agreement and subsequent Decision No. 75322 expressly exclude recovery of unrecovered costs from residential customers.

**Q: Mr. Yaquinto, was AIC a signatory to the 2011 APS rate case Settlement Agreement?**

---

[2] Decision No. 75748 (September 19, 2016).

[3] Direct Testimony of Charles Miesner at 52:13-16.

A: Yes. AIC supported the Settlement Agreement because it produced an overall result that was fair to the Company, its shareholders, and its customers. My testimony in support of that Settlement Agreement also stated my belief it was in the public interest for the Commission to approve the Settlement Agreement.

In reaching the Settlement Agreement, the signatories engaged in a give-and-take process resulting in certain compromises and future expectations. One such expectation, as outlined in the Settlement Agreement, was that the AG-1 experimental rate would have a limited duration of four years and that the mitigation program would offset unrecovered costs of the program. However, neither of these expectations have been met.

**Q: Why do you oppose the AG-1 program?**

A: I oppose renewing the program for several reasons.

First, the AG-1 program has resulted in unrecovered costs, which have been borne solely by shareholders and customers not participating in the program. Very simply, the program is not cost based and the mitigation program has not fully offset unrecovered fixed costs. According to APS witness Leland Snook, "To date, the mitigation has been $24,427,000 less than the lost margins on a cumulative basis."[4] This is the approximate loss through the end of the AG-1 program's original termination date, July 1, 2016.

Moreover, losses have continued since the AG-1 program was extended beyond its original expiration date, despite the Commission authorizing APS to defer a portion of the unmitigated losses for potential future recovery. The Commission must now decide who bears those costs in this case.

[4] Direct Testimony of Leland Snook at 43: 26-27.

Second, the AG-1 program benefits only a select group of very large customers who possess the sophisticated skills and knowledge required to understand and access complex power generation markets. It also benefits a few out-of-state generation providers eager to sell large amounts of power to Arizona customers. The benefits to these few entities has come largely at the expense of the Company, which is required by law to design and construct facilities to serve all customers, including those seeking power from alternative providers.

Third, as APS witness Snook states in his testimony, the AG-1 program has flaws that prevent the Company from fully recovering costs related to the delivery of alternative generation service to customers.[5] For example, Mr. Snook states that the administrative fee of $0.60 per MWh for administering the program should be ***at least*** three times larger to fully recover these costs. Mr. Snook also mentions the capacity reserve charge and energy imbalance charges as insufficient to cover the actual costs for these services as well.

Further, Mr. Snook's testimony on these matters is based on the recommendations contained in the Company's report on AG-1's unmitigated losses, "APS AG-1 Program Evaluation" attached to Mr. Snook's testimony.[6] The report was required as a provision in the 2012 Settlement Agreement, which authorized the AG-1 experimental program.

Finally, while I am not an attorney, I believe the AG-1 program exhibits characteristics of retail electric generation competition, which presents significant legal issues that should not be overlooked.

---

[5] *Id.* at 44-45.
[6] *Id.* at LRS-06DR.

**Q: Mr. Yaquinto, you seem adamantly opposed to either renewal or expansion of the AG-1 tariff. Should the Commission nevertheless decide to renew this rate rider, do you have an opinion on how to minimize its harm?**

A: Although AIC supports neither renewal nor expansion of the AG-1 program, should the Commission decide it should be renewed, it should be modified so that the program fully recovers its costs from participants.

Setting potential legal issues aside for the moment, I believe any buy-through program authorized by the Commission should remain a narrowly-constructed experiment, with a capped MW participation level, and appropriately designed to recover all costs, as opposed to being predicated on less than efficacious mitigation measures. It should also be limited in scope and duration and periodically re-evaluated. This means that AG-1 participants should be required to pay the full costs of service under the program, including all unrecovered fixed costs, as well as the administration and management costs identified in Mr. Snook's testimony. Should it be allowed to continue, the AG-1 program should remain as an experimental program of limited duration and size. Large commercial and industrial customers should not be permitted to avoid costs which are then shifted onto other customers or shareholders.

Finally, by its terms, the original AG-1 experimental rate rider requires the contract between the customer and the wholesale provider not exceed a four year period – the intended initial duration of the program. If the program continues in its existing or modified form, the Commission's approval of the continued program should operate as a reset and APS should be allowed to evaluate new applications under the 200 MW cap and conduct a new lottery if necessary.

**Q: Mr. Yaquinto, what is your recommendation to the Commission?**

A: I recommend the Commission not renew or otherwise expand the AG-1 experimental program.

**Q: Does this conclude your testimony?**

A: Yes.

# Exhibit GMY1-DR

# ARIZONA INVESTMENT COUNCIL'S FIRST SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN DOCKET NO. E-01345A-16-0036 AND DOCKET NO. E-01345A-16-0123 DECEMBER 28, 2016

AIC 1.1: Arizona Public Service ("APS") agreed in its 2012 Rate Case Settlement Agreement to forgo recovery or deferment of costs associated with AG-1.

(a) What has been the financial net impact of the program to APS since its inception through the date of this data request?

(b) What is the forecasted total financial net impact of the program to APS by June 30, 2017 or when new rates are anticipated to go into effect?

Response: (a),(b) The requested information is provided in attachment APSRC01810.

Witness: Chuck Miessner

AG-1 tracking information

| | ($000) 2012 - 2014 | 2015 | 2016 YTD Sept | Actual Total |
|---|---|---|---|---|
| Revenue | (110,727) | (55,468) | (45,389) | (211,584) |
| Fuel-related | 67,430 | 33,411 | 27,345 | 128,186 |
| Unrecovered costs | (43,297) | (22,057) | (18,044) | (83,398) |
| AG-1 fees | 5,494 | 2,753 | 2,315 | 10,562 |
| Margin mitigation | 25,071 | 7,609 | 5,911 | 38,591 |
| Net margin Impact | (12,732) | (11,695) | (9,818) | (34,245) |

notes: data rounded to nearest $000
net margin impact is also referred to as operating income before taxes in pro forma

**Forecast AG-1 Revenues/Costs and Margin**
**Period Jul 2016 to Jun 2017**
**(dollars in thousands)**

| | | Actuals | | | Estimates | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Line No. | | Jul-16 | Aug-16 | Sep-16 | Oct-16 | Nov-16 | Dec-16 | Jan-17 | Feb-17 | Mar-17 | Apr-17 | May-17 | Jun-17 | Period Ttl |
| 1. | AG-1 Revenues | | | | (2,147) | (1,968) | (1,995) | (1,899) | (1,756) | (1,983) | (2,182) | (2,363) | (2,128) | (18,421) |
| 2. | AG-1 Purchase Power over/under base | | | | (497) | (491) | (461) | (403) | (417) | (457) | (688) | (761) | (486) | (4,661) |
| 3. | AG-1 Off-System Margin Deferral | | | | (458) | (294) | (285) | (220) | (238) | (237) | (44) | (63) | (405) | (2,244) |
| 4. | AG-1 Margin | | | | (1,191) | (1,183) | (1,250) | (1,276) | (1,101) | (1,289) | (1,450) | (1,538) | (1,237) | (11,515) |
| 5. | Cummlative Margin | | | | (1,191) | (2,375) | (3,624) | (4,900) | (6,001) | (7,290) | (8,740) | (10,278) | (11,515) | |
| 6. | Deferrable margin at 90% | | | | (1,191) | (1,183) | (1,250) | (1,276) | (1,101) | (1,289) | - | - | 278 | |
| 7. | Deferrable margin at 100% | | | | - | - | - | - | - | - | (1,450) | (1,538) | (1,515) | |
| 8. | Allowable AG-1 Margin Deferral | (1,395) | (923) | (1,084) | (1,072) | (1,065) | (1,125) | (1,148) | (991) | (1,160) | (1,450) | (1,538) | (1,265) | **(14,217)** |
| 9. | Depreciation amortization annual impact (line 8 divide by 5) | | | | | | | | | | | | | **(2,843)** |

**BEFORE THE ARIZONA CORPORATION COMMISSION**

**COMMISSIONERS**

TOM FORESE – Chairman
BOB BURNS
DOUG LITTLE
ANDY TOBIN
BOYD DUNN

| | |
|---|---|
| IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN. | DOCKET NO. E-01345A-16-0036 |
| IN THE MATTER OF FUEL AND PURCHASED POWER PROCUREMENT AUDITS FOR ARIZONA PUBLIC SERVICE COMPANY. | DOCKET NO. E-01345A-16-0123 |

Direct Rate Design Testimony of

**Branko Terzic**

On Behalf Of

Arizona Investment Council

February 3, 2017

**Q: Please state your name, address, and occupation.**

A: My name is Branko Terzic. I am a Managing Director at the Berkeley Research Group LLC. My business address is 1800 M Street N.W. Washington, DC, 20036.

**Q: Have you previously filed testimony in this proceeding?**

A: Yes. I filed Direct Testimony regarding revenue requirement on December 28, 2016.

**Q: What is the purpose of your rate design direct testimony in this proceeding?**

A: This portion of my testimony is to support Arizona Public Service Company's ("APS") proposal to implement a nearly universal three-part rate design, which includes a demand charge for capacity-related costs.

**Q: What is APS's proposal?**

A: APS proposes to modernize rates by making demand charges the standard feature of all rates offered to residential customers, with the exception of a small subset of small usage customers.

Demand rates are not new for APS or the Commission. The Commission, like other public utility commissions across the country, has for years supported demand charges for business and industrial customers. Additionally, APS and the Commission have over 35 years of experience with an optional residential demand rate for APS customers.[1] The direct testimony of APS Witness Mr. Charles Miessner states that over 120,000 APS residential customers are on a

[1] Direct Testimony of Charles Miessner at 18:17.

three part demand rate.[2] Moreover, a substantial portion of those 120,000 customers were able both to reduce demand and consume less energy after changing to the three part rate design.[3] APS's proposal would expand that beneficial opportunity to all residential consumers.

**Q: Are demand rates for residential consumers a new idea?**

**A:** Not at all. The concept of three-part rates is almost as old as energy billing itself. According to Harry Barker's Public Utility Rates (McGraw Hill 1917), demand charges originated in 1892 when the British engineer Dr. John Hopkinson introduced the idea of viewing demand and energy as independent billing components. What is now known as the "Hopkinson Demand Rate" has a number of variations with respect to how the rate can be structured into blocks of usage or demand. In fact, demand rates with block structures have been widely used for the commercial and industrial rate classes. While demand rates for residential customers were discussed and contemplated over a hundred years ago, the consumption level of that class was considered too low to justify the cost of the electric meter required to bill the more sophisticated rate design.

---

[2] *Id.* at 18:14.
[3] *Id.* at 20:5-10.

**Q: What was rate design intended to accomplish for residential customers a century ago?**

A: A primary consideration for residential customer rate design a century ago was that residential customers consumed far less energy compared to industrial customers and thus lacked the requisite experience with the new product to understand any form of rate design that varied by time of use or other factor. As electrical engineer Harry Barker writes in his 1917 :

> The problem of securing a good rate schedule for residential supply customers is particularly difficult compared with industrial supply customers. The latter are more apt to have enough technical knowledge to understand two-part and three-part charge and their long hours of general use generally result in satisfactory low cost of energy. The former require a very simple tariff for them to understand, while their service is in peak-load hours and of short duration so that their cost of energy is apt to be comparatively high – although they readily cannot see how. It is universally desirable that the residential consumer should be well satisfied and that the tariff should be framed so as to stimulate longer hours of use.[4]

In other words, the goal of utility rate design for residential customers in the early 1900s was to stimulate consumption of electricity – an end that would not be achieved were residential customers billed *on two or* three part rates.

**Q: Do residential customers use electricity differently today than they did in 1917?**

A: Yes, the difference in usage is night and day. First, residential customers in 2017 are generally far more sophisticated and knowledgeable about assessing complicated pricing schemes and buying goods and services than they were a century ago. A typical 2017 consumer is faced daily with a multitude of

[4] Harry Barker, Public Utility Rates 111 (McGraw Hill 1917).

complicated service offerings. An average adult consumer compares and selects, for example:

- voice and data pricing packages from a variety of mobile telephone companies;
- various casualty and health insurance options;
- multi-faceted home financing and mortgage packages;
- credit card offerings that contain various and often elaborate benefit schemes;
- bundled cable and telephone service packages versus satellite offerings; and
- complicated rooftop solar leasing contracts.

The list could go on and on. Given the wealth of experience today's customers have in assessing complicated service offerings, a typical energy consumer likely has enough familiarity with complex payment considerations to understand a three-part electric rate. As stated above, 120,000 APS customers have already demonstrated that they not only understand the rate design, but know how to change their behavior in order to lower their electric bills.

Another significant difference in the electric industry environment between 1917 and 2017 is that, in 1917, utilities were attempting to *increase* the residential load on the system, not lower it, as they are today. The average annual residential customer's electric use in 1914 was 268 kWh *per year*; in 2015, the average APS's residential customers purchased 12,522 kwh that year.[5]

[5] 2015 APS FERC Form No. One at page 304.

Because the ultimate goal at the turn of the 20th century was to increase the amount of electricity that residential customers used, residential electricity tariffs at that time were designed to encourage the addition of new electric devices and otherwise increase electric load and consumption levels. That goal stands in stark contrast to the policy directive today, which is to *reduce* electricity consumption and load. For good reason, utilities today are making significant efforts to decrease peak usage, improve load factors, and minimize energy consumption. An important means of achieving those outcomes is to design rates that send accurate price signals for demand and energy, thus encouraging customers to change their inefficient usage patterns and become more cost-effective for utilities to serve. Today's outdated rate design does not do the trick. Residential tariffs should evolve to reflect today's policy goals, not those of 100 years ago.

Finally, the cost of meters in 1917 was significant compared to the total cost of service and the residential consumer's total bill. Because residential customers were not a significant revenue source, investing in the type of meter necessary to bill a sophisticated rate design (to the extent such meters were even available) did not make sense for the residential class. That is not the case today where metering costs, even for the most sophisticated meters, are low compared to the generation, transmission and distribution costs incurred by consumers. Perhaps more important, APS already has metering infrastructure in place for all residential customers that can accommodate a three part rate design, thus rendering any metering concern moot.

**Q: Please describe the difference between demand and energy.**

**A:** Electric service has to fulfill two basic requirements: providing energy and supplying power (power may also be referred to as demand, capacity, or load, depending on the point of reference). "Energy" is generally defined as the "capacity to do work." For electric utility billing purposes, energy is the total electricity consumption measured in kilowatt-hours (kWhs) over a one month period.

"Power" is the rate at which energy is used by or delivered to a customer at any given point in time. Under our current form of regulation, electricity service must be sufficiently robust to provide the exact amount of power required by the customer at the moment the customer needs it.

"Demand" is the customer's requirement for power. Demand will vary during the day, month, season, and year. Unfortunately, most consumers have experienced a blown fuse or a tripped circuit breaker when the capacity of their home's internal wiring has been exceeded by the electric "power" required when they have plugged one too many electric devices into that particular circuit.

The key to the regulatory requirement that a utility provide adequate service is to ensure that the utility meets each customer's maximum, or peak, demand. "Capacity" in this context describes the ability of the electric power system, or grid, to adequately serve the combined customer maximum demand or "load" requirements (in terms of kilowatts or megawatts). So the customer's instantaneous demand for power must be met, at any time of day or night, by the electric utility's installed capacity in generation, transmission and delivery.

**Q: What is a demand charge?**

A: Electric service is divided into requirements for demand measured in kWs and energy measured in kWh. The demand charge is the part of a bill that recovers costs based on the customer's maximum usage over a specified period of time. The electric utility must have adequate facilities to meet each customer's individual peak demand as well as the system's collective peak demand. A demand charge recovers the cost of this service and is expressed in terms of dollars per kW of demand. In this case, APS is proposing that the demand charge reflect the customer's highest level of demand as averaged over a one hour period during the month. This results in a lower demand charge than would be calculated if APS used the 15 minute demand standard currently approved for business customers. The reason for this is that many home appliances and devices, especially those with motors, show a short demand spike when first engaged. The demand spike is to overcome the initial inertia and get the motor spinning. There are kitchen appliances and temperature responsive refrigerators and air conditioners which kick in for much shorter than one hour periods. Thus, a fifteen minute average demand standard would result in higher average demand calculation than does a one hour standard.

**Q: Why do you support residential demand rates?**

A: I support residential demand rates because applying a three part rate to residential customers reflects sound ratemaking principles and benefits both the electric system and the customer. Specifically, APS's proposal will:

1) better align residential electric rates with the cost of service;
2) provide improved cost signals to incent economic usage of electricity; and
3) afford consumers the opportunity to reduce monthly bills through modern residential energy management techniques and technologies.

**Q: How does the grid benefit from mandatory residential demand rates?**

A: Investment in the electric power system includes investments in generation, transmission, and distribution facilities. The system is built with sufficient capacity to meet the peak load/demand of current and forecasted future customers. Total system costs increase when peak usage rises, which means that new capital costs are incurred when peak demand grows. Conversely, total system costs can decline when usage is shifted away from the peak and new costs are avoided when there is no growth in peak load.

Three-part rates provide consumers with the ability to benefit from lower bills if they reduce their demand. They can do this by staggering the use of their appliances throughout the day, thereby lowering demand while using the same amount of energy or kWhs. Put another way, by spreading out the use of high demand appliances (those with motors, heaters, or pumps, such as washing machines, clothes dryers, and dishwashers), customers will save on their utility bill.

For customers that want to go a step further, there are new home energy management systems that can help monitor demand, as well as new and evolving energy efficiency programs and companies to assist.

**Q: Can the system benefits you mention above be achieved through a time of use rate alone?**

A: No. The ability to influence downward peak demand is a unique benefit of the demand-charge rate design. While an energy-only time of use rate might incidentally mitigate the demand a customer places on the system, such a result is not inherent in the rate design. Put another way, a time of use rate is not designed to reduce demand – it is designed to shift the hours during which energy is used. A customer on an energy only time of use rate might shift its load to a certain low-cost energy time period, but actually increase its system demand. Such a result does not allow the utility to avoid the cost of new peak capacity infrastructure. Only a demand charge provides the right pricing incentive to encourage customers to focus on minimizing how much power they pull from the grid at any one point in time. Avoiding the cost of new peak capacity infrastructure provides a benefit to all system users

**Q: Do you believe that demand rates are too complicated for residential customers to understand?**

**A:** No. There has been criticism about the general public's ability to understand demand rates since the topic was originally discussed in 1917. The original criticism is summarized below:

> While the multi-part tariff may be wholly logical, it may be so complex and unintelligible to the customer that he cannot checkup his bill by any instruments on his premise and this may create a fundamental prejudice against the utility. Then the disadvantages outweigh the benefits of the schedule in most cases.[6]

I do not believe that this critique is valid in 2017. It was made during a period of time when the economics of metering itself was being debated. In some places, the normal electricity tariff was an un-metered charge of $0.75 per lamp or motor per month.[7] Even during this time period, Barker observed that utilities were looking to introduce "unit charges with a device attempting to bring the price automatically close to the cost of service large and small consumers" and that "…it is not possible to cut loose from 'cost-of-service.'"[8]

As I indicated earlier, the modern consumer of 2017 is making numerous economic decisions for complicated services, many of which did not exist 100 years ago when the consumer comprehension concern surrounding residential

---

[6] Harry Barker, Public Utility Rates 7 (McGraw Hill 1917).
[7] *Id.* at 8.
[8] *Id.* at 7.

three-part rates first arose. In this regard, APS is well positioned to help its customers learn to manage the rate, in large part because it has had the experience of providing three-part rate information to thousands of residential customers for the better part of four decades.[9] The APS Customer Education and Transition Plan is based on that experience and expertise. Few regulatory commissions looking at demand-charge proposals would have such a wealth of local experience available. To that point, the Arizona Corporation Commission has the opportunity to lead the country by implementing an effective consumer education process using the unique data it has at its disposal.

**Q: Are demand rates fair to rooftop solar customers?**

A: Absolutely. Whenever a customer is connected to the grid, it can impose a demand on the utility at any time. Whether or not that customer has solar on its rooftop, the utility must meet that customer's demand. The higher the demand, the greater the investment required of the utility. Rooftop solar customers, like all other customers, place demand on the system and must pay for the capacity-related grid services that the utility is required to provide them.

**Q: Does this conclude your testimony?**

A: Yes, it does.

[9] Direct Testimony of Charles Miessner at 18:14

**BEFORE THE ARIZONA CORPORATION COMMISSION**

**COMMISSIONERS**

TOM FORESE – Chairman
BOB BURNS
DOUG LITTLE
ANDY TOBIN
BOYD DUNN

| | |
|---|---|
| IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN. | DOCKET NO. E-01345A-16-0036 |
| IN THE MATTER OF FUEL AND PURCHASED POWER PROCUREMENT AUDITS FOR ARIZONA PUBLIC SERVICE COMPANY. | DOCKET NO. E-01345A-16-0123 |



Direct Rate Design Testimony of

**Daniel G. Hansen**

on Behalf of

Arizona Investment Council

February 3, 2017

# TABLE OF CONTENTS

## I. INTRODUCTION AND PURPOSE

**Q: Please state your name, position, and business address.**

A: My name is Daniel G. Hansen. I am a Vice President at Christensen Associates Energy Consulting, LLC, located at Suite 400, 800 University Bay Drive, Madison, Wisconsin 53705.

**Q: Have you previously testified in utility regulation proceedings?**

A: Yes. I have testified in Arizona, Colorado, Connecticut, Minnesota, New Mexico, Nevada, Oregon, and Utah. In these proceedings, I represented a broad range of clients, including a regulator, an environmental organization, a non-profit organization of utility investors, and investor-owned utilities. My education and work experience are described in AIC Exhibit DGH-1DR.

**Q: On whose behalf are you testifying in this docket?**

A: I am testifying on behalf of the Arizona Investment Council ("AIC").

**Q: What is the purpose of your direct testimony?**

A: The purpose of my testimony is to provide support and recommendations regarding the fixed cost recovery and residential rate design proposals of Arizona Public Service Company ("APS"). Specifically, my testimony will include the following:

- Support for full revenue decoupling in place of APS's proposed Lost Fixed Cost Recovery ("LFCR") mechanism;
- Support for the proposed LFCR mechanism if full revenue decoupling is rejected (*i.e.*, as a second-best method of addressing fixed cost recovery and utility disincentives to promote conservation and energy efficiency); and
- Support for APS's residential rate design proposals, including the application of a demand charge for all but the lowest-use residential customers.

## II. REVENUE DECOUPLING IS BETTER THAN A LFCR MECHANISM

**Q: What is revenue decoupling?**

A: Revenue decoupling is a means of removing a utility's disincentive to promote conservation and energy efficiency ("EE"). It accomplishes this by removing ("decoupling") the link between a utility's sales and its fixed cost recovery, which is caused by the fact that retail rates typically recover a significant share of the utility's fixed costs through volumetric (*i.e.*, per-kWh) charges.

**Q: How are revenue decoupling mechanisms designed?**

A: While revenue decoupling mechanism designs may differ, the basic structure is conceptually simple. A deferral account (*i.e.*, similar to other utility tracking accounts) is established and dollars are added to or subtracted from it using the following formula (where $t$ designates a time period, such as a billing month): $\text{Deferral}_t = (\text{Allowed Revenue})_t - (\text{Billed Revenue})_t$. When allowed revenue is greater than billed revenue in a given month, dollars are added to the deferral tracking account for future collection from customers (via a future rate increase). Conversely, when allowed revenue is *less than* billed revenue, dollars are subtracted from the deferral tracking account and refunded to customers via a future rate decrease. The most significant differences across revenue decoupling mechanisms relate to the calculation of Allowed Revenue. For example, Allowed Revenue can be a pre-specified total dollar amount or a pre-specified dollar amount per customer served.

**Q: Is there a form of revenue decoupling that serves as the focus of your testimony?**

A: Yes. When I refer to the potential application of revenue decoupling to APS, I refer to full revenue per customer decoupling. The "full" descriptor indicates that the Allowed and Billed Revenue amounts are not adjusted for the effect of weather (or any other factor) in the deferral calculation. The "revenue per customer" descriptor indicates that Allowed Revenue is calculated by multiplying the number of customers served in the current month by a fixed dollar amount per customer, which is specified in a rate case (in much the same way that a retail rate is set).

**Q: Does APS discuss revenue decoupling in its application?**

A: Yes. APS witness Snook discusses revenue decoupling (which he calls a "Revenue Stabilization Mechanism" or "RSM") on pages 34 through 36 of his direct testimony. After describing the merits of a RSM, he states that APS is not proposing one for the following reason:

> Throughout the stakeholder process leading up to this filing, APS heard concerns from various stakeholders about the RSM, particularly in combination with APS' residential rate reform proposals. While APS believes the RSM would be a complement to its rate reform proposals, a number of other parties see it differently. APS listened during the stakeholder process to these concerns and determined this case was not the appropriate time to propose the RSM.[1]

**Q: Do you believe stakeholders are correct in preferring a LFCR mechanism to revenue decoupling?**

A: No, I believe revenue decoupling should be preferred to a LFCR mechanism. However, I note that a LFCR mechanism is preferred to the absence of any mechanism to address utility fixed cost recovery, and that the modifications to the existing LFCR mechanism proposed by APS would improve its performance. Based on my review of the Settlement Agreement from APS's 2011 rate case (E-01345A-11-0224), I believe the opposition to revenue decoupling is based on several misconceptions. In the remainder of this section, I will address these misconceptions and describe why revenue decoupling is superior to a LFCR mechanism.

[1] Direct Testimony of Leland R. Snook at 35: 22-27.

**Q: What reasons were given for rejecting APS's revenue decoupling proposal in its 2011 rate case?**

A: A number of perceived problems with revenue decoupling were cited in Staff testimony, including the following:

- Decoupling shifts weather and economic risk from the utility to its customers;[2]
- The ability of the utility to benefit from prolonged outage events;
- The "pancaking" of increases;
- The incentive to game inputs; and
- The problem of how to appropriately reflect the level of risk in the cost of equity when setting the Company's rates.[3]

**Q: Do you agree that those issues are good reasons to use a LFCR mechanism in place of revenue decoupling?**

A: No, the issues are either misconceptions or minor in comparison to the benefits of revenue decoupling versus a LFCR mechanism. I will address each point below.

**Q: Do you agree that full revenue decoupling shifts weather risk from the utility to its ratepayers?**

A: No, revenue decoupling does not shift weather risk from the utility to its ratepayers. This is a very common misconception and is typically stated without evidence or explanation as though it is obviously true. A reduction in risk for one party does not imply that the risk is shifted to a counterparty. A simple illustration will help explain this. Imagine two co-workers who start every work day by flipping a coin. If the coin comes up heads, Person A gives Person B $20. If it comes up tails, Person B gives Person A $20. Both people face what I'll call "coin flipping risk", or the chance

---

[2] Direct Testimony of Howard Solganick at 8: 8-20. (Docket No. E-01345A-11-0224, November 18, 2011).

[3] The second through fifth bullet points are from of Decision No. 73183 at 22:22-24 (May 24, 2012).

they'll gain or lose $20 each day. Now suppose Person A is tired of facing the coin flipping risk every day and ends the game. As a result of ending the game, Person A's coin flipping risk is gone. Did the risk shift to Person B? Clearly not, as Person B also faces no coin flipping risk as a result of Person A's decision to end the game. The coin flipping risk has been eliminated for both people.

**Q: Does that simple example have any relevance to the context of this rate case?**

**A:** Yes. Weather risk is quite similar to the coin flipping risk described above. Person A and Person B are analogous to the utility and its ratepayers. The coin flips are analogous to experiencing weather that is more extreme or mild than the normal weather conditions upon which rates are based (*e.g.*, mild weather results in reduced sales, which causes the utility to lose money while its ratepayers benefit by paying less toward fixed-cost recovery). Full revenue decoupling is analogous to ending the coin flipping game and results in a reduction (or perhaps elimination) of weather risk for both the utility and its ratepayers.

**Q: Is there a general rule that describes when risk can be reduced for both parties?**

**A:** Yes. Risk can be reduced for both parties (*e.g.*, the utility and its ratepayers) when outcomes cause one party to benefit at the other's expense (i.e., when the parties have negatively correlated risk). In the case of weather (when fixed costs are recovered through volumetric rates and there is no decoupling mechanism), an unusually hot summer benefits the utility at the expense of its ratepayers while a mild summer benefits the ratepayers at the expense of the utility. Removing the opportunity for the utility to be harmed by weather also removes the opportunity for ratepayers to be harmed by it.

**Q: Is it possible that revenue decoupling could shift *any* risk from the utility to its ratepayers?**

A: It is possible that revenue decoupling could shift economic risk from the utility to its customers, though the magnitude of that specific risk can be reduced by using a revenue-per-customer decoupling mechanism. Under a revenue-per-customer model, the outcomes for the two parties are in the same direction. For example, if customers respond to a recession by reducing their usage (attempting to reduce their utility bill), the utility will be made worse off by the sales reduction at the same time customers are made worse off by the recession. However, there is an important limitation on the potential for the transfer of economic risk: if the decoupling mechanism uses a revenue-per-customer methodology (as APS proposed in 2011), the utility will retain all economic risk that results in a change in the number of customers served. For example, if a housing crisis results in a reduction in the number of residential customers, the utility's total allowed revenue will be scaled down as the number of customers served declines. Under revenue-per-customer decoupling, economic risk can only be shifted through changes in use per customer.

**Q: Continuing with the list of perceived problems with revenue decoupling, do you believe that it allows the utility to benefit from prolonged outages?**

A: No, revenue decoupling does not allow the utility to benefit from prolonged outages. First, outages are *de minimis* in the context of revenue decoupling. APS witness Tetlow presents APS's historical outage information from 2005 through 2015. During that time period, its highest System Average Interruption Duration Index (SAIDI) value was 108 (in 2005) and its lowest SAIDI value was 70 (in 2012).[4] The difference between the highest and lowest reliability year amounted to a difference of 0.007 percent of APS's sales. In short, outages are very unlikely to be a problem worth worrying about. If stakeholders disagree about the potential magnitude of the effect of

[4] Direct Testimony of Jacob Tetlow at 8: Figure 2.

outages in a decoupling mechanism, it would be straightforward to implement a SAIDI-based adjustment to allowed revenues, thus eliminating any possibility that the utility could be made whole by decoupling deferrals following a failure to adequately address outages.

**Q: Do you believe the potential for the "pancaking" of rate increases is a reason to reject revenue decoupling?**

A: No. The term "pancaking" appears to refer to the possibility that a mild weather year could be followed by an extreme weather year, such that the decoupling-induced rate increase from the mild year results in higher rates during the extreme weather year, when some customers may be experiencing weather-related bill increases. I don't believe this is a reason to prefer a LFCR mechanism over revenue decoupling for the following reasons. First, a cap on the allowed annual rate increase can prevent the magnitude of the rate increase from being onerous in any given year. Second, under revenue decoupling, customers could experience "reverse pancaking," in which a decoupling-induced rate decrease brings rate relief during an extreme weather year. My examination of year-to-year changes in CDDs[5] from 1996 through 2015 shows that the pancaking scenario (below normal followed by above-normal weather) occurs only four times. "Reverse" pancaking occurs three times during the same time period. In short, pancaking is an issue that can be managed with cap provisions, is unlikely to occur often, and is offset by the possibility of "reverse" pancaking occurring with approximately the same frequency.

**Q: Do you believe that revenue decoupling introduces incentives to game inputs?**

A: No, I do not believe that revenue decoupling introduces incentives to game inputs. The elements that go into setting the parameters of the decoupling mechanism (the

[5] CDDs are cooling degree days measured with a 65-degree threshold. See AIC Exhibit DGH-2DR, APS's response to AIC 1.8.

test-year sales, number of customers served, and fixed costs per kWh) are already determined in the rate case. If there is an incentive to game those values, it is not qualitatively different than the incentive to game them in the setting of standard rates.

**Q: Do you agree that implementing revenue decoupling makes it is difficult to appropriately reflect the level of risk in the cost of equity when setting rates?**

A: No. APS witness Villadsen discusses this issue in Section VI of her Direct Testimony (pages 53-56), concluding:

> Because a large number of the companies in my sample have decoupling mechanisms in place, any impact on the cost of equity is already captured in my estimates. Further, empirical research have not detected any relationship between the cost of equity and decoupling, so there is no evidence that decoupling affect the cost of equity. Therefore, decoupling should not affect the allowed ROE.[6]

Dr. Villadsen's conclusions are consistent with a recent Order in Minnesota, which found:

> First, many of the companies in the comparison group had decoupling rate designs, demonstrating the similarity in investment risk required for a reliable DCF analysis. Second, the record contained a study by a national research and consulting group showing "no significant evidence of a decrease in the cost of capital following adoption of decoupling." And finally, the Company's cost-of-equity expert witness provided a detailed analysis of a representative company's extensive and long-term experience with decoupling, which demonstrated that decoupling had no measurable impact on its cost of capital.[7]

In summary, a recent Order is consistent with the arguments made by APS witness Villadsen regarding the effect of revenue decoupling on the cost of equity.

**Q: Please summarize this section of your testimony.**

A: In this section, I have addressed each of the objections raised to revenue decoupling in APS's previous rate case, in which a LFCR mechanism was implemented as part of

---

[6] Direct Testimony of Bente Villadsen at 56: 15-19.

[7] Findings of Fact, Conclusions, and Order, Minnesota Public Utilities Commission Docket No. E-002/GR-13-868, page 57.

a settlement agreement. The stated problems are either inconsequential (*e.g.*, outages) or based on misconceptions (*i.e.*, decoupling does not shift weather risk from the utility to its ratepayers). In the next section, I will describe the reasons that revenue decoupling is a better method than a LFCR mechanism for addressing utility incentives to promote conservation and energy efficiency.

## III. THE LFCR MECHANISM SHOULD BE ENHANCED IF REVENUE DECOUPLING IS NOT ADOPTED

**Q: Please describe how a LFCR mechanism functions.**

A: Under a LFCR mechanism, the Commission approves a rate that represents the amount of lost fixed costs per kWh (as defined and allowed in the mechanism), which is then multiplied by the measured and verified energy savings from the utility's EE programs and distributed generation ("DG"). The total amount of lost fixed costs allowed under the mechanism, calculated as the product of the EE and DG kWh and the cent-per-kWh fixed cost rate, is recovered through an increase in customer rates in the following year.

**Q: Why do you believe revenue decoupling should be implemented in place of APS's LFCR mechanism?**

A: The most important advantage of a revenue decoupling mechanism relative to a LFCR mechanism is that it more completely addresses the utility's incentive issues to promote conservation and EE. A LFCR mechanism only addresses the utility's incentives to promote the programs included in the mechanism. It does not address the utility's incentive to increase customer usage or its disincentives to engage in conservation-promoting activities that are not subjected to measurement and valuation, including (as described by SWEEP in its Opening Brief to APS's 2011 rate case) "utility support for building energy codes and appliance standards, broad energy education and marketing, state and local government energy conservation efforts, and federal energy policies."[8] Other benefits of revenue decoupling include the ability to: reduce weather risk for both the utility and its ratepayers; reduce the potential for conflicts regarding the measurement and valuation of EE savings; and produce rate adjustments that can be positive or negative (whereas a LFCR mechanism can only increase rates).

**Q: The settlement agreement from the 2011 rate case touted the LFCR mechanism's "narrowly tailored" approach as a benefit.[9] Do you agree that a narrow approach is necessarily preferred to a "broad" approach?**

**A:** No, the expanded scope of revenue decoupling is the characteristic that enables it to perform better than a LFCR mechanism. The fact that *all* changes in use per customer are included in decoupling deferrals (versus only sales decreases attributable to utility-sponsored EE programs and DG) accomplishes the following:

- Eliminates the need for measurement and valuation to calculate deferrals, thus removing utility disincentives to promote programs for which benefits are not easily measured;
- Reduces weather risk for both the utility and its ratepayers. Eliminating the ability of the utility to "lose" during mild weather conditions also eliminates the ability of customers to "lose" during above-normal weather conditions.
- Removes the utility's incentive to *increase* use per customer, because any resulting gains would have no effect on its revenue.

**Q: Many of these benefits of revenue decoupling were discussed in APS's 2011 rate case. Why do you think the ACC should conclude differently in this rate case?**

**A:** As described in Section II, my review of the Settlement Agreement and Order from Docket No. E-01345A-11-0224 indicated that, in my opinion, the key reasons for

---

[8] Southwest Energy Efficiency Project's Opening Brief at 3:20-22 (Docket No. E-011345A-11-0224).
[9] Decision No. 73183 at 18:13 (May 24, 2012).

rejecting revenue decoupling in favor of a LFCR mechanism were not well founded. Notably, revenue decoupling does *not* shift weather risk from the utility to its ratepayers. In addition, revenue decoupling more fully addresses utility disincentives to promote conservation (and its incentives to promote load growth) than a LFCR mechanism. My views are consistent with the ACC's Policy Statement on revenue decoupling, which states: "Revenue decoupling may offer significant advantages over alternative mechanisms for addressing utility financial disincentives to energy efficiency, as it establishes better certainty of utility recovery of authorized fixed costs and better aligns utility and customer interests."[10] This policy statement followed in-depth discussions of the issue during four workshops that took place from April through June 2010. I hope the additional discussion provided here persuades stakeholders to reconsider their opposition to revenue decoupling for APS.

**Q: What do you recommend in the event that revenue decoupling is rejected?**

**A:** In the absence of implementing revenue decoupling, I recommend the ACC approve the continued use of the LFCR mechanism, including the suggested modifications of APS witness Snook.[11] While I firmly believe revenue decoupling is superior to a LFCR mechanism, I approve of the LFCR approach as a second-best option. That is, it has the benefit of addressing *some* of the utility's disincentive issues, even if its coverage is incomplete.

**Q: Do you support APS's proposed enhancements to the LFCR mechanism?**

A: Yes. APS has proposed five modifications to its LFCR mechanism, as follows:

1. Changing the filing and effective dates for the annual adjustments;
2. Increasing the year-over-year cap from 1 percent to 2 percent;
3. Updating the costs eligible for recovery;

[10] ACC Policy Statement Regarding Utility Disincentives to Energy Efficiency and Decoupled Rate Structures, Docket No. E-00000J-08-0314, December 29, 2010, page 30.
[11] Direct Testimony of Leland R. Snook at 36-37.

4. Removing the opt-out rate option; and

5. Applying the adjustment to the per-kW charge or the per-kWh charge (if the customer does not pay a per-kW charge).[12]

I will focus on the third modification, which I believe is particularly important for adequately addressing APS's disincentives to promote EE.

**Q: How will accepting APS's recommendation to update the applicable costs improve the LFCR mechanism?**

A: The recommendation helps reduce APS's disincentive to promote EE. APS is proposing to include 100 percent of the transmission, distribution, and generation costs collected through energy charges, and 50 percent of the transmission, distribution, and generation costs collected through demand charges. The current LFCR mechanism excludes all generation costs and 50 percent of the distribution and transmission costs collected through demand charges. Any fixed costs that are excluded from the LFCR mechanism and recovered through volumetric rates present APS with a disincentive to promote EE. This disincentive is reduced by including more of those costs in the LFCR mechanism. APS witness Snook testified that the inclusion of generation costs in the LFCR mechanism will not allow APS to profit from selling the energy saved by customers into the wholesale market, as the margins from those transactions are returned to APS's customers.[13]

---

[12] *Id.* at 36: 7-22.
[13] *Id.* at 37: 7-10.

## IV. SUPPORT FOR APS'S RESIDENTIAL RATE PROPOSALS

**Q: How would you describe APS's residential rate design proposals?**

A: APS is proposing to greatly expand the application of three-part pricing to its residential customers, exempting only low-use customers and grandfathered partial requirements customers.

**Q: What rate designs does APS propose for its residential customers?**

A: APS has proposed to replace its existing options with three options (with two exceptions noted below). Each of these options includes a basic service charge ("BSC"), and peak-period demand charge, and time-of-use ("TOU") energy charges. I will characterize these options as "three-part" rates, which refers to the fact that they have three types of charges: customer-related, demand-related, and energy-related. The options differ according to the relative magnitudes of the charges, as qualitatively described below (where the terms "high," "low," and "medium" are based on comparisons across the three options):

- R-1: high BSC, low demand charge, high energy charges.
- R-2: low BSC, medium demand charge, high energy charges.
- R-3: high BSC, high demand charge, low energy charges.

Low-use customers, defined as full requirements customers (*i.e.*, those without DG) using less than 600 kWh per month, are offered an additional rate option (R-XS) that contains only a BSC and a flat annual energy charge. New partial requirements customers (*i.e.*, those with DG) will be required to take service on Rate R-3. Existing partial requirements customers will continue to take service under their current rate design, with the rates scaled to correspond to the revenue requirement from this rate case.[14]

[14] Direct Testimony of Charles A. Miessner at 3-5.

**Q: Has APS taken any measures to address customer bill impacts or in the interest of gradualism?**

A: Yes, APS has taken several measures to address these issues:

- Proposed a "demand limiter" that sets a cap on a customer's billed demand (applicable only to full requirements customers). The maximum billed demand is set such that the customer's monthly load factor (the ratio of the customer's average hourly usage to its billed demand) is no lower than 15 percent.[15] This protection limits the extent to which customers can experience "bill surprises" from unusually high demand hours in the event they initially have difficulty managing their demand.
- Limit the magnitude of the demand charge by including only a portion of demand-related costs in the rate. As described by APS witness Miessner, APS's proposal to set rates that are not fully aligned with the cost of service "will provide a significant step toward improved alignment with cost of service while allowing customers time to get used to the new rates, especially the demand charge component."[16]
- Proposed Rate R-XS, which may alleviate concerns about potential bill impacts for low-income customers, who are often believed to be disproportionately represented among low-use customers.
- Continuation, with some modifications, of the Limited-Income Bill Discount Programs, or E-3 and E-4 rate riders. These programs provide direct bill payment assistance to low-income customers.

**Q: Do you support the residential rate proposals described above?**

A: Yes. I will describe the benefits of three-part pricing below.

**Q: What are the benefits of including a demand charge in retail rates?**

---

[15] *Id.* at 29: 17-18.
[16] *Id.* at 37: 23-27.

**A:** Including a demand charge (in addition to a BSC and energy charges) in a retail rate provides customers with rates that better reflect the way utility costs are incurred. This has several potential benefits, including:

- Giving customers appropriate incentives to manage their demand, thereby promoting a more efficient use of the system;
- Encouraging customers to adopt (and third parties to produce innovations in) capacity-saving technologies;
- Preventing the need for future rate modifications in response to emerging issues; and
- Reducing intra-class cross subsidies.

**Q: How does APS's three-part rate design better reflect the way utility costs are incurred?**

**A:** APS's three-part rate has charges that better reflect the way utility costs are incurred, relative to a comparable non-demand rate. It is commonly accepted in utility cost-of-service studies that costs within functions (generation, transmission, distribution, and customer service) can be classified according to their primary driver, which can be one of the following:[17]

- **Customer-related costs**, which increase as the utility serves more customers, regardless of the amount of energy the customers use;
- **Energy-related costs**, which vary with the amount of energy used by customers; and
- **Demand-related costs**, which are associated with the maximum amount of energy used during a specified time interval (*e.g.*, 15 to 60 minutes).

APS's proposed residential rates contain charges that correspond to each of these cost drivers (with the exception of Rate R-XS).

---

[17] National Association of Regulatory Utility Commissioners, Electric Utility Cost Allocation Manual, January 1992, pages 20-22.

**Q: How can customers benefit from managing their demand on a three-part rate?**

A: When customers who take service on a three-part rate reduce their billed demand, they can reduce their bill while at the same time contributing to lower utility costs in the short- and/or long-run. Customers can reduce billing demand by avoiding using electricity intensive appliances at the same time, ensuring that their demand stays low even if their total energy consumption changes little (*e.g.*, by delaying washing clothes when the dishwasher is running).

**Q: How do three-part rates encourage adoption of capacity-saving technologies?**

A: Enabling technology can assist customers in managing their end uses to minimize billed demand. For example, the Residential Demand Control program at Otter Tail Power Company includes a demand controller and radio receiver to automate control of the end-uses during "control periods," which are called by the utility. In addition, the Rocky Mountain Institute (RMI) produced a report on this topic called "The Economics of Demand Flexibility."[18] This study simulated the potential for customer bill savings on a variety of residential rates, with the largest simulated benefits coming from Salt River Project's residential demand rate. In addition, demand-based rates give customers with rooftop solar installations an incentive to invest in battery storage technologies, which can be used to help the customer manage its billing demand. This technology has the ability to effectively turn distributed solar power from an intermittent resource into a dispatchable resource. In the absence of the demand charge (or TOU pricing), a net-metered customer has little reason to invest in battery storage.[19]

---

[18] "The Economics of Demand Flexibility", Rocky Mountain Institute, August 2015. The report is available for download at RMI's web site: http://www.rmi.org/electricity_demand_flexibility.

[19] In this case, the customer's incentive to invest in battery storage would likely be limited to improved reliability (in case of service interruption).

**Q: How do three-part rates reduce the need for future rate modifications in response to emerging issues?**

**A:** Demand-based rates have the potential to reduce the need for future rate modifications in response to emerging issues because they better reflect the way utility costs are incurred. That is, a well-designed retail rate is more likely to function well in a variety of circumstances. For example, APS's proposed rate structures remove the need for a separate electric vehicle ("EV") charging rate because, as APS witness Miessner noted, "the proposed demand rate options will provide ample incentive for customers to delay charging their vehicles until after 8 p.m. Therefore, a special electric vehicle rate is no longer needed."[20]

**Q: How do three-part rates reduce intra-class cross subsidies?**

**A:** Three-part rates reduce intra-class cross subsidies by making the charges customers pay more closely reflect the way utility costs are incurred. A utility must have enough generating capacity (through ownership or purchase agreements) and network capability to serve peak demands. Under two-part rates, these demand-related costs are included in the energy charges. Therefore, customers who have relatively low levels of energy use contribute little to fixed-cost recovery regardless of the level of their maximum demand. A customer with low energy use relative to its demand level is referred to as a "low load factor" customer.[21] Under two-part rates, low load factor customers tend to be subsidized by high load factor customers (those whose average usage is closer to their maximum demand). A customer's low load factor may be caused by a high proportion of AC load, seasonal occupancy of a residence (reducing the customer's annual load factor), or the installation of on-site DG. By reflecting the customer's load factor in their rates (as three-part rates do), high load factor customers will pay a lower average rate than low load factor customers (all else

[20] Direct Testimony of Charles A. Miessner at 35: 22-24.

[21] Load factor is defined as the average usage over a period of time divided by the customer's maximum demand over that same period of time (where the period of time is typically one month or year).

equal), which is consistent with utility cost-of-service methods. That is, demand-based rates give customers an incentive to use the utility's assets more efficiently (*e.g.*, helping prevent the need for a generating unit designed to serve a low number of peak hours each year).

**Q: What problems are caused by recovering fixed costs through energy charges for NEM customers?**

A: When net metered rates recover fixed costs through volumetric charges, the reduction in billed sales to the NEM customers reduces utility fixed-cost recovery, which leads to a combination of cross-subsidies (*i.e.*, an increase in rates to non-NEM customers) and reduced opportunity for the utility to earn its authorized rate of return. In the short run, some of the lost fixed cost recovery from NEM will be shifted to other customers through the LFCR mechanism. Remaining unrecovered fixed costs that are not shifted to other customers through the LFCR mechanism are borne by the utility until rates are re-set during APS's next rate case. In the rate case, the reduced level of test-year billed sales associated with DG leads to an increase in the energy charges that are paid by all customers in the rate class. That is, the fixed cost recovery will be spread across fewer billing units, so the resulting energy charge (which is the test-year revenue requirement divided by the test-year sales) is higher. While this rate reset theoretically makes the utility whole for NEM at test-year sales going forward, the class-wide increase in rates that results from net metered output from customer-sited DG perpetuates the shift of fixed-cost recovery from NEM customers to non-NEM customers.

**Q: Is it appropriate to make three-part rates mandatory for customers who install distributed generation (DG)?**

A: Yes. The cross subsidy described above can be mitigated through three-part pricing. After installing DG, customers are likely to experience larger decreases in their billed energy than their maximum demand. In many cases, NEM customers have zero or negative billed kWh during a billing month. However, due to the intermittency of their DG, it is unlikely that such customers have zero demand. In the absence of a demand-based charge, the utility cannot collect any revenue to cover demand-related fixed costs.

**Q: Do you have any evidence that NEM customers have different usage characteristics than non-NEM customers?**

A: Yes. I examined monthly billing data for 2015 provided by APS in response to AURA's Data Request 1.18.[22] I focused on NEM and non-NEM customers on two rates: E-12 (the Standard Rate) and ET-2 (Time Advantage 7PM-NOON). I conducted two comparisons: the percentage of bills that record zero billed kWh and the average monthly load factor for NEM and non-NEM customers.[23] Table 1 below shows the results. Notice that NEM customers have a much higher share of bills with zero billed usage (30+ percent versus 2.2 percent or less for non-NEM customers) and that their August load factor is considerably lower. The frequent absence of billed kWh for NEM customers helps demonstrate the difficulty in collecting demand-related costs through per-kWh rates from these customers. The lower load factor for NEM customers provides additional evidence that a two-part rate designed to recover the allowed revenue requirement from the class-average customer will under-recover costs from NEM customers and over-recover them from non-NEM customers.

---

[22] Note that I omitted November data from my analyses, as it appears NEM customer data were not included in that month's data. NEM customers were present in the files for all other billing months. I also limited my analysis to customers with 25 to 34 days in the billing month.

[23] I calculated load factor as: {kWh / (# Days in Billing Month x 24 hours)} / Maximum Demand.

**Table 1: Comparison of NEM and Non-NEM 2015 Billing Data**

| Statistic | Rate E-12 | | Rate ET-2 | |
|---|---|---|---|---|
| | Non-NEM Customers | NEM Customers | Non-NEM Customers | NEM Customers |
| % of bills with 0 billed kWh | 2.2% | 36.5% | 0.1% | 32.4% |
| August Load Factor | 0.322 | 0.205 | 0.403 | 0.241 |

**Q: You proposed the adoption of full revenue decoupling for APS. Would such a mechanism reduce the need for, or appeal of three-part pricing?**

A: No. Revenue decoupling is not a substitute for three-part pricing. Revenue decoupling does not affect (or has very minor effects) on customer incentives to invest in demand management technologies (*e.g.*, advanced thermostats or battery storage for DG customers). That is, the decoupling-induced rate changes do not affect the fundamental nature of the customer's rate structure (*i.e.*, it doesn't turn a two-part rate into a three-part rate). In addition, NEM-related cross-subsidies are not remedied by revenue decoupling. Under decoupling, the reduced fixed cost recovery from NEM customers is spread across the sales to the entire customer class, including non-NEM customers. Decoupling produces the same type of NEM cost shift that occurs under a rate case or LFCR mechanism, it just occurs during a different time frame. This is not to undermine the benefits of revenue decoupling. As described in Section II, I believe decoupling is an effective means of addressing utility incentives to support EE. Rather, I am pointing out that revenue decoupling accomplishes a different goal than three-part pricing. The two methods coexist effectively.

## V. CONCLUSIONS

**Q: Do you have any concluding observations?**

A: Yes, I conclude that revenue decoupling is a better method of addressing APS's disincentive to promote EE than a LFCR mechanism. Previous arguments against decoupling appeared to be based on misconceptions (*e.g.*, that it shifts weather risk from the utility to its ratepayers). Revenue decoupling offers a more complete solution to APS's incentive issues than a LFCR mechanism. However, should revenue decoupling fail to receive widespread support, I recommend the Commission approve the LFCR mechanism for continued use, including the modifications proposed by APS. In addition, I recommend the approval of APS's proposed residential rate modifications that expand the application of three-part pricing, which would improve customer incentives to manage their demand, encourage investments in capacity-saving technologies, prevent the need for future rate modifications in response to emerging issues, and reduce intra-class cross subsidies.

**Q: Does this conclude your direct testimony?**

A: Yes.

Exhibit DGH-1DR

and

Exhibit DGH-2DR

# Daniel G. Hansen

RESUME

January 2017

**Address:**

800 University Bay Drive, Suite 400
Madison, WI 53705–2299
Telephone: 608.231.2266
Fax: 608.231.2108
Email: dghansen@caenergy.com

**Academic Background:**

Ph.D., Michigan State University, 1997, Economics
M.A., Michigan State University, 1993, Economics
B.A., Trinity University, 1991, Economics and History

**Positions Held:**

Vice President, Laurits R. Christensen Associates, Inc. 2006–present
Senior Economist, Laurits R. Christensen Associates, Inc., 1999–2005
Economist, Laurits R. Christensen Associates, Inc., 1997–1999

**Professional Experience:**

I work in a variety of areas related to retail and wholesale pricing in electricity and natural gas markets. I have used statistical models to forecast customer usage, estimate customer load response to changing prices, and estimate customer preferences for product attributes. I have developed and priced new product options; evaluated existing pricing programs; evaluated the risks associated with individual products and product portfolios; and developed cost-of-service studies. I have conducted evaluations and provided testimony regarding revenue decoupling and weather adjustment mechanisms.

**Major Projects:**

Assisted a utility in forecasting the load impacts from a new residential peak-time rebate program.

Evaluated residential demand response pilot programs with programmable-controllable thermostats.

Developed long-term forecasting models for an electric utility.

Conducted a review of an electric utility's load forecasting methods.

Conducted an independent evaluation of a revenue decoupling mechanism for an electric utility.

Estimated load impacts for commercial and industrial demand response programs.

Evaluated a straight-fixed variable rate design for a natural gas utility.

Estimated the load impacts from a residential peak-time rebate program.

Worked with a state's regulatory staff to evaluate alternative electricity pricing structures for residential, commercial, and industrial customers.

Assisted a utility in meeting regulatory requirements regarding the allocation of distribution services.

Evaluated a residential electricity pricing pilot program.

Evaluated the cost effectiveness of automated demand response technologies.

Evaluated and modified short- and long-term electricity sales and demand forecasting models.

Created a short-term electricity demand forecasting model.

Prepared testimony regarding the return on equity effects associated with natural gas revenue decoupling mechanisms.

Conducted an independent evaluation of two natural gas revenue decoupling mechanisms

Created forecasts of load impacts from electricity demand response programs.

Estimated historical the load impacts from electricity demand response programs.

Prepared testimony regarding a proposed natural gas decoupling mechanism.

Prepared testimony regarding the weather normalization of test year sales and revenues.

Participated on a regulatory proceeding panel to discuss decoupling mechanisms.

Prepared testimony regarding a proposed electricity decoupling mechanism.

Prepared a report and testimony regarding a natural gas decoupling mechanism.

Evaluated a model that estimated the costs associated with removing and relicensing hydroelectric facilities.

Assisted an electric utility in evaluating new rate options for commercial and industrial customers.

Designed and evaluated time-of-use and critical-peak pricing rates for an electric utility.

Reviewed cost-of-service study for a municipal electric utility.

Produced a report on rate design methods that provide appropriate incentives for demand response and energy efficiency.

Assisted in wholesale power procurement process.

Evaluated a weather-adjustment mechanism for a natural gas utility.

Assessed weather-related fixed cost recovery risk for an electric utility.

Evaluated a revenue decoupling mechanism for a natural gas utility.

Estimated price responsiveness of real-time pricing customers.

Evaluated the need for electricity transmission and distribution standby rates for a utility.

Developed a market share simulation model using conjoint survey results of electricity distributors.

Conducted conjoint surveyed of electricity distributors regarding rate structure preferences.

Developed a method to calculate a retail forward contract risk premium.

Prepared a report on the performance of Financial Transmission Rights (FTRs) in the PJM electricity market.

Reviewed a retail pricing model for use in a competitive electricity market.

Provided support in a natural gas rate case filing.

Simulated outcomes associated with alternative wholesale rate offers to electricity distributors.

Developed a business case to support a natural gas fixed bill product.

Assessed the accuracy of a natural gas fixed bill pricing algorithm.

Audited an evaluation of the costs associated with implementing a renewable portfolio standard.

Developed a model to value interruptible provisions in a long-term customer contract.

Performed a study on the determinants of electricity price differences across utilities and regions.

Developed long-term demand and energy forecasts.

Conducted market research to assess customer interest in new product options.

Recommended new retail pricing products for commercial and industrial customers.

Prepared a report on the fundamentals of retail electricity risk management.

Prepared a report that presented a taxonomy of retail electricity pricing products.

Presented at a workshop in Africa regarding deregulated electricity markets.

Prepared a report on the effectiveness of distributed resources in mitigating price risk.

Performed a valuation of energy derivatives consistent with FAS 133.

Created an electricity market share forecasting model.

Developed standby rates for an electric utility.

Developed an electricity wholesale price forecast.

Forecasted retail customer loads for an electric utility.

Assisted in mediating a new product development process with a utility and its industrial customers.

Developed a model that simulates wholesale market price changes due to retail load response.

Developed a pricing model for an innovative financial product.

Estimated changes in wholesale electricity prices due to customer load response.

Oversaw creation of software that estimates customer satisfaction with utilities.

Developed a model to economically evaluate a capital addition to a generator.

Developed a wholesale version of the Product Mix Model.

Evaluate Risk Implications of New Product Offering.

Mixed Logit Estimation of Customer Preferences.

Estimation of Customer Price Responsiveness.

Product Mix Model Workshops.

Unbundling and Rate Design.

Development of a Computer Program.

Large Commercial and Industrial Customer Rate Analysis.

Residential Customer Rate Analysis.

Survey of Power Marketers.

Development of Multi-Period Analysis Tool.

Evaluating the Effect of Alternative Rates on System Load.

Estimating the Persistence of Weather Patterns.

Electricity Customer Survey Data Analysis.

Product Mix Analysis for Small Customers.

Survey of Postal Facilities.

**Professional Papers:**

"2015 Load Impact Evaluation of Pacific Gas and Electric Company's Residential Time-Based Pricing Programs: *Ex-post* and *Ex-ante* Report," with Steven Braithwait and David Armstrong, 2016.

"2015 Load Impact Evaluation of Pacific Gas and Electric Company's Mandatory Time-of-Use Rates for Small, Medium, and Agricultural Non-residential Customers: *Ex-post* and *Ex-ante* Report," with Marlies Patton, 2016.

"2015 Load Impact Evaluation of California Statewide Demand Bidding Programs (DBP) for Non-Residential Customers: *Ex-post* and *Ex-ante* Report," with Michael Ty Clark, 2016.

"2015 Load Impact Evaluation of California Statewide Base Interruptible Programs (BIP) for Non-Residential Customers: *Ex-post* and *Ex-ante* Report," with Tim Huegerich, 2016.

"Statewide Time-of-Use Scenario Modeling for 2015 California Energy Commission Integrated Energy Policy Report," with Steven Braithwait and David Armstrong, 2015.

"2014 Statewide Load Impact Evaluation of California Aggregator Demand Response Programs: *Ex-post* and *Ex-ante* Load Impacts," with Steven Braithwait and David Armstrong, 2015.

"2014 Load Impact Evaluation of California Statewide Demand Bidding Programs (DBP) for Non-Residential Customers: *Ex-post* and *Ex-ante* Report," with Steven Braithwait and David Armstrong, 2015.

"2014 Load Impact Evaluation of California Statewide Base Interruptible Programs (BIP) for Non-Residential Customers: *Ex-post* and *Ex-ante* Report," with Tim Huegerich, 2015.

"2014 Load Impact Evaluation of Southern California Edison's Mandatory Time-of-Use Rates for Small and Medium-Sized Business and Agricultural Customers: *Ex-post* and *Ex-ante* Report," with Marlies Patton, 2015.

"2014 Load Impact Evaluation of Pacific Gas and Electric Company's Mandatory Time-of-Use Rates for Small and Medium Non-residential Customers: *Ex-post* and *Ex-ante* Report," with Marlies Patton, 2015.

"FirstEnergy's Smart Grid Investment Grant Consumer Behavior Study," with EPRI (B. Neenan) and Marlies Patton, 2015.

"An Evaluation of Portland General Electric's Decoupling Adjustment, Schedule 123," with Robert J. Camfield and Marlies C. Hilbrink, 2013.

"Evaluation of the Straight-Fixed Variable Rate Design Implemented at Columbia Gas of Ohio," with Marlies C. Hilbrink, 2012.

"The Effect on Electricity Consumption of the Commonwealth Edison Customer Application Program Pilot," with EPRI and CA Energy Consulting staff, 2012.

"The Effects of Critical Peak Pricing for Commercial and Industrial Customers for the Kansas Corporation Commission," with David A. Armstrong, 2012.

"Meeting Commonwealth Edison's Distribution Allocation Requirements from Illinois Commerce Commission Order 10-0467," with Michael O'Sheasy, A. Thomas Bozzo, and Bruce Chapman, 2011.

"Residential Rate Study for the Kansas Corporation Commission," with Michael T. O'Sheasy, 2011.

"An Evaluation of the Conservation Incentive Program Implemented for New Jersey Natural Gas and South Jersey Gas," with Bruce R. Chapman, 2009.

"A Review of Natural Gas Decoupling Mechanisms and Alternative Methods for Addressing Utility Disincentives to Promote Conservation," June 2007.

"Evaluation of the Klamath Project Alternatives Analysis Model: Reply to Addendum A of the Consultant Report Prepared for the California Energy Commission Dated March 2007," May 2007, with Laurence D. Kirsch and Michael P. Welsh.

"Evaluation of the Klamath Project Alternatives Analysis Model," March 2007, with Laurence D. Kirsch and Michael P. Welsh.

"A Review of the Weather Adjusted Rate Mechanism as Approved by the Oregon Public Utility Commission for Northwest Natural," October 2005, with Steven D. Braithwait.

"A Review of Distribution Margin Normalization as Approved by the Oregon Public Utility Commission for Northwest Natural," March 2005, with Steven D. Braithwait.

"Analysis of PJM's Transmission Rights Market," EPRI Report #1008523, December 2004, with Laurence Kirsch.

"Using Distributed Resources to Manage Price Risk," EPRI Report #1003972, November 2001, with Michael Welsh.

"Hedging Exposure to Volatile Retail Electricity Prices," *The Electricity Journal*, Vol. 14, number 5, pp. 33–38, June 2001, with A. Faruqui, C. Holmes and B. Chapman.

"Weather Hedges for Retail Electricity Customers," with C. Holmes, B. Chapman and D. Glyer. In papers for EPRI International Pricing Conference 2000.

"Worker Performance and Group Incentives: A Case Study," *Industrial and Labor Relations Review*, Vol. 51, No. 1, pp. 37–49, October 1997.

"Worker Quality and Profit Sharing: Does Unobserved Worker Quality Bias Firm-Level Estimates of the Productivity Effect of Profit Sharing?" Working Paper, May 1996.

"Supervision, Efficiency Wages, and Incentive Plans: How Are Monitoring Problems Solved?" Working Paper, November 1996, presented at the Western Economics Association Meetings, 1997.

"Has Job Stability Declined Yet? New Evidence for the 1990's," with David Neumark and Daniel Polsky, *The Journal of Labor Economics*, 1999.

**Testimony and Reports before Regulatory Agencies:**

Black Hills/Colorado Electric Utility Company, Colorado Docket No. 16A-0436E: Testimony supporting energy and demand forecasting models on behalf of Black Hills/Colorado Electric Utility Company, 2016.

UNS Electric, Inc., Arizona Docket No. E–04204A-15-0142: Testimony supporting a residential demand charge proposed by UNS Electric on behalf of the Arizona Investment Council, 2015.

Public Service Company of New Mexico (PNM), New Mexico Case No. 15-00261-UT: Testimony supporting a revenue decoupling mechanism on behalf of PNM, 2015.

Public Service Company of New Mexico (PNM), New Mexico Case No. 14-00332-UT: Testimony supporting a revenue decoupling mechanism on behalf of PNM, 2014.

Xcel Energy, Inc., Minnesota E002/GR-13-868: Testimony supporting a revenue decoupling mechanism on behalf of Xcel Energy, 2013.

Arizona Public Service Company, Arizona Docket No. E–01345A–11–0224: Testimony supporting a revenue decoupling mechanism proposed by APS on behalf of the Arizona Investment Council, 2011.

Southwest Gas Corporation, Arizona Docket No. G–01551A–10–0458: Testimony supporting a revenue decoupling mechanism contained in a settlement agreement on behalf of the Arizona Investment Council, 2011.

Otter Tail Power Company, Minnesota Docket No. E–017/GR–10–239: Testimony regarding the weather normalization of test year sales in a general rate case on behalf of Otter Tail Power Company, 2010.

Southwest Gas Corporation, Nevada Docket No. 09–04003: Testimony regarding the return on equity effects associated with a proposed revenue decoupling mechanism on behalf of Southwest Gas Corporation, 2009.

Southwest Gas Corporation, Arizona Docket No. G–01551A–07–0504: Testimony regarding a proposed revenue decoupling mechanism on behalf of the Arizona Investment Council, 2008.

Otter Tail Power Company, Minnesota Docket No. E–017/GR–07–1178: Testimony regarding the weather normalization of test year sales and revenues in a general rate case on behalf of Otter Tail Power Company, 2008.

Massachusetts Department of Public Utilities, Docket No. DPU 07–50: Participation in a panel regarding an "Investigation into Rate Structures that will Promote Efficient Deployment of Demand Resources", on behalf of Environment Northeast, 2007.

Connecticut Light & Power Company, Docket No. 07–07–01: Testimony regarding a proposed electricity revenue decoupling mechanism on behalf of Environment Northeast, 2007.

Questar Gas Company, Docket No. 05–057–T01: Testimony regarding the effectiveness of a natural gas revenue decoupling mechanism on behalf of the Utah Division of Public Utilities, 2007.

PacifiCorp, FERC Docket No. 2082: "Evaluation of the Klamath Project Alternatives Analysis Model: Reply to Addendum A of the Consultant Report Prepared for the California Energy Commission Dated March 2007," May 2007, with Laurence D. Kirsch and Michael P. Welsh.

PacifiCorp, FERC Docket No. 2082: "Evaluation of the Klamath Project Alternatives Analysis Model," March 2007, with Laurence D. Kirsch and Michael P. Welsh.

Northwest Natural Gas Company, Oregon Docket UG 163: Testimony relating to an investigation regarding possible continuation of Distribution Margin Normalization, May 2005.

Northwest Natural Gas Company, Oregon Docket UG 152: Submitted a report in compliance with a requirement to evaluate the functioning of the Weather Adjusted Rate Mechanism, October 2005.

# ARIZONA INVESTMENT COUNCIL'S FIRST SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN DOCKET NO. E-01345A-16-0036 AND DOCKET NO. E-01345A-16-0123 DECEMBER 28, 2016

AIC 1.8: Please provide the normal weather data used by APS to produce the test-year billing determinants.

(a) Please provide similarly formatted historical weather data for up to 20 prior years.

Response: Please refer to workpapers CAM_WP01 pages 4-7, 11-12, and CAM_WP15 pages 16-55. Additionally, please see attachment APSRC01809 for the requested historical data.

Witness: Miessner/Ewen

**Response to Data Request AIC 1.8**

## ARIZONA PUBLIC SERVICE COMPANY
## BILLING MONTH ACTUAL AND NORMAL WEATHER--RESIDENTIAL
## AS OF DECEMBER 31, 2015

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Residential HDDs (base 65°)** | | | | | | | | | | | | | |
| 2006 | 217 | 192 | 132 | 55 | NA | NA | NA | NA | NA | NA | 1 | 161 | 758 |
| 2007 | 376 | 282 | 126 | 23 | NA | NA | NA | NA | NA | NA | 4 | 152 | 963 |
| 2008 | 367 | 321 | 136 | 16 | NA | NA | NA | NA | NA | NA | 10 | 130 | 980 |
| 2009 | 306 | 170 | 77 | 29 | NA | NA | NA | NA | NA | NA | 33 | 188 | 803 |
| 2010 | 300 | 214 | 160 | 37 | NA | NA | NA | NA | NA | NA | 15 | 160 | 886 |
| 2011 | 298 | 274 | 134 | 33 | NA | NA | NA | NA | NA | NA | 28 | 194 | 961 |
| 2012 | 284 | 191 | 122 | 37 | NA | NA | NA | NA | NA | NA | 16 | 98 | 748 |
| 2013 | 389 | 227 | 145 | 7 | NA | NA | NA | NA | NA | NA | 9 | 198 | 975 |
| 2014 | 229 | 112 | 13 | 5 | NA | NA | NA | NA | NA | NA | 15 | 114 | 488 |
| 2015 | 299 | 76 | 38 | 1 | NA | NA | NA | NA | NA | NA | 44 | 237 | 695 |
| Normals 10-years ending Dec 2015 | 307 | 206 | 108 | 24 | NA | NA | NA | NA | NA | NA | 18 | 163 | 826 |
| **Residential CDDs (base 80°)** | | | | | | | | | | | | | |
| 2006 | NA | NA | NA | NA | 63 | 294 | 497 | 435 | 300 | 126 | NA | NA | 1,715 |
| 2007 | NA | NA | NA | NA | 79 | 256 | 504 | 421 | 480 | 165 | NA | NA | 1,905 |
| 2008 | NA | NA | NA | NA | 27 | 184 | 466 | 434 | 341 | 191 | NA | NA | 1,643 |
| 2009 | NA | NA | NA | NA | 91 | 206 | 436 | 511 | 395 | 169 | NA | NA | 1,808 |
| 2010 | NA | NA | NA | NA | 12 | 160 | 463 | 456 | 394 | 245 | NA | NA | 1,730 |
| 2011 | NA | NA | NA | NA | 19 | 134 | 440 | 476 | 512 | 220 | NA | NA | 1,801 |
| 2012 | NA | NA | NA | NA | 84 | 276 | 466 | 462 | 363 | 159 | NA | NA | 1,810 |
| 2013 | NA | NA | NA | NA | 73 | 306 | 497 | 456 | 388 | 94 | NA | NA | 1,814 |
| 2014 | NA | NA | NA | NA | 43 | 283 | 448 | 447 | 348 | 124 | NA | NA | 1,693 |
| 2015 | NA | NA | NA | NA | 28 | 213 | 479 | 474 | 415 | 201 | NA | NA | 1,810 |
| Normals 10-years ending Dec 2015 | NA | NA | NA | NA | 52 | 231 | 470 | 457 | 394 | 169 | NA | NA | 1,773 |
| **Humidity** | | | | | | | | | | | | | |
| 2006 | NA | NA | NA | NA | 19.7 | 14.9 | 23.0 | 35.2 | 36.4 | 28.6 | NA | NA | |
| 2007 | NA | NA | NA | NA | 21.9 | 14.4 | 17.4 | 37.8 | 29.3 | 25.7 | NA | NA | |
| 2008 | NA | NA | NA | NA | 15.5 | 20.2 | 24.5 | 32.5 | 37.1 | 25.7 | NA | NA | |
| 2009 | NA | NA | NA | NA | 19.4 | 19.5 | 22.5 | 22.5 | 26.1 | 22.5 | NA | NA | |
| 2010 | NA | NA | NA | NA | 21.4 | 16.4 | 18.3 | 34.3 | 29.2 | 28.4 | NA | NA | |
| 2011 | NA | NA | NA | NA | 16.9 | 13.9 | 19.9 | 29.0 | 25.8 | 23.7 | NA | NA | |
| 2012 | NA | NA | NA | NA | 17.9 | 13.6 | 23.9 | 32.8 | 38.4 | 26.6 | NA | NA | |
| 2013 | NA | NA | NA | NA | 15.1 | 13.6 | 23.1 | 30.7 | 34.4 | 22.9 | NA | NA | |
| 2014 | NA | NA | NA | NA | 15.0 | 12.7 | 21.6 | 31.3 | 36.0 | 38.7 | NA | NA | |
| 2015 | NA | NA | NA | NA | 26.1 | 22.8 | 25.1 | 29.9 | 36.7 | 37.5 | NA | NA | |
| Normals 10-years ending Dec 2015 | NA | NA | NA | NA | 18.9 | 16.2 | 21.9 | 31.6 | 32.9 | 28.0 | NA | NA | |

# ARIZONA PUBLIC SERVICE COMPANY
## BILLING MONTH ACTUAL AND NORMAL WEATHER--RESIDENTIAL
## AS OF DECEMBER 31, 2015

| Weather | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2006 | 217 | 192 | 132 | 55 | 187.8 | 794.2 | 1,558.3 | 1,549.1 | 1,078.4 | 422.5 | 1 | 161 | |
| 2007 | 376 | 282 | 126 | 23 | 243.8 | 682.8 | 1,439.7 | 1,529.2 | 1,621.2 | 535.7 | 4 | 152 | |
| 2008 | 367 | 321 | 136 | 16 | 74.0 | 553.0 | 1,490.6 | 1,510.9 | 1,232.2 | 620.1 | 10 | 130 | |
| 2009 | 306 | 170 | 77 | 29 | 269.8 | 611.9 | 1,357.5 | 1,591.0 | 1,288.5 | 526.2 | 33 | 188 | |
| 2010 | 300 | 214 | 160 | 37 | 36.8 | 447.6 | 1,345.9 | 1,612.0 | 1,329.4 | 819.9 | 15 | 160 | |
| 2011 | 298 | 274 | 134 | 33 | 53.7 | 352.7 | 1,315.9 | 1,602.8 | 1,664.2 | 696.4 | 28 | 194 | |
| 2012 | 284 | 191 | 122 | 37 | 242.3 | 720.4 | 1,479.0 | 1,612.6 | 1,324.2 | 521.7 | 16 | 98 | |
| 2013 | 389 | 227 | 145 | 7 | 198.2 | 798.7 | 1,560.5 | 1,561.5 | 1,372.8 | 294.3 | 9 | 198 | |
| 2014 | 229 | 112 | 13 | 5 | 116.4 | 719.3 | 1,376.6 | 1,539.3 | 1,247.1 | 453.3 | 15 | 114 | |
| 2015 | 299 | 76 | 38 | 1 | 91.3 | 666.0 | 1,543.8 | 1,610.6 | 1,495.2 | 728.5 | 44 | 237 | |
| Normals 10-years ending Dec 2015 | 307 | 206 | 108 | 24 | 151 | 635 | 1,447 | 1,572 | 1,365 | 562 | 18 | 163 | |

**Response to Data Request AIC 1.8**

## ARIZONA PUBLIC SERVICE COMPANY
## BILLING MONTH ACTUAL AND NORMAL WEATHER–GENERAL SERVICE
## AS OF DECEMBER 31, 2015

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| General Service CDDs (base 65°) | | | | | | | | | | | | | |
| 2006 | NA | NA | 21 | 141 | 400 | 747 | 953 | 878 | 757 | 524 | 220 | NA | 4,641 |
| 2007 | NA | NA | 90 | 211 | 409 | 708 | 960 | 866 | 942 | 567 | 333 | NA | 5,086 |
| 2008 | NA | NA | 39 | 183 | 399 | 577 | 926 | 876 | 801 | 603 | 276 | NA | 4,680 |
| 2009 | NA | NA | 78 | 127 | 438 | 661 | 895 | 955 | 859 | 569 | 241 | NA | 4,823 |
| 2010 | NA | NA | 10 | 103 | 268 | 578 | 914 | 894 | 849 | 668 | 254 | NA | 4,538 |
| 2011 | NA | NA | 48 | 199 | 344 | 557 | 895 | 920 | 970 | 627 | 278 | NA | 4,838 |
| 2012 | NA | NA | 28 | 185 | 472 | 743 | 940 | 911 | 834 | 577 | 252 | NA | 4,942 |
| 2013 | NA | NA | 68 | 245 | 464 | 762 | 959 | 913 | 854 | 462 | 194 | NA | 4,921 |
| 2014 | NA | NA | 95 | 208 | 403 | 732 | 909 | 905 | 815 | 561 | 294 | NA | 4,922 |
| 2015 | NA | NA | 116 | 279 | 334 | 627 | 940 | 923 | 887 | 633 | 218 | NA | 4,957 |
| Normals 10-years ending Dec 2015 | NA | NA | 59 | 188 | 393 | 669 | 929 | 904 | 857 | 579 | 256 | NA | 4,834 |
| Humidity | | | | | | | | | | | | | |
| 2006 | NA | NA | 29.1 | 29.2 | 19.7 | 14.9 | 23.0 | 35.2 | 36.4 | 28.6 | 28.1 | NA | |
| 2007 | NA | NA | 29.2 | 28.1 | 21.9 | 14.4 | 17.4 | 37.8 | 29.3 | 25.7 | 22.5 | NA | |
| 2008 | NA | NA | 37.2 | 19.5 | 15.5 | 20.2 | 24.5 | 32.5 | 37.1 | 25.7 | 24.2 | NA | |
| 2009 | NA | NA | 32.0 | 21.7 | 19.4 | 19.5 | 22.5 | 22.5 | 26.1 | 22.5 | 24.9 | NA | |
| 2010 | NA | NA | 48.4 | 29.3 | 21.4 | 16.4 | 18.3 | 34.3 | 29.2 | 28.4 | 34.0 | NA | |
| 2011 | NA | NA | 30.8 | 25.2 | 16.9 | 13.9 | 19.9 | 29.0 | 25.8 | 23.7 | 29.9 | NA | |
| 2012 | NA | NA | 27.9 | 22.7 | 17.9 | 13.6 | 23.9 | 32.8 | 38.4 | 26.6 | 25.6 | NA | |
| 2013 | NA | NA | 32.3 | 20.7 | 15.1 | 13.6 | 23.1 | 30.7 | 34.4 | 22.9 | 27.8 | NA | |
| 2014 | NA | NA | 30.1 | 19.2 | 15.0 | 12.7 | 21.6 | 31.3 | 36.0 | 38.7 | 34.0 | NA | |
| 2015 | NA | NA | 35.3 | 20.5 | 26.1 | 22.8 | 25.1 | 29.9 | 36.7 | 37.5 | 40.2 | NA | |
| Normals 10-years ending Dec 2015 | NA | NA | 33.2 | 23.6 | 18.9 | 16.2 | 21.9 | 31.6 | 32.9 | 28.0 | 29.1 | NA | |
| Weather | HDDs (base 65°) | HDDs (base 65°) | | | | | | | | | | HDDs (base 65°) | |
| 2006 | 217 | 192 | 70.8 | 475.8 | 1,192.2 | 2,017.9 | 2,988.1 | 3,126.6 | 2,721.1 | 1,757.2 | 733.9 | 161 | |
| 2007 | 376 | 282 | 303.7 | 703.8 | 1,262.4 | 1,888.4 | 2,742.2 | 3,145.6 | 3,181.7 | 1,840.8 | 1,036.8 | 152 | |
| 2008 | 367 | 321 | 141.0 | 543.6 | 1,093.6 | 1,734.3 | 2,962.0 | 3,049.6 | 2,894.5 | 1,957.6 | 879.4 | 130 | |
| 2009 | 306 | 170 | 270.3 | 390.8 | 1,298.8 | 1,963.4 | 2,786.6 | 2,973.4 | 2,802.0 | 1,771.6 | 774.8 | 188 | |
| 2010 | 300 | 214 | 38.8 | 347.9 | 821.0 | 1,616.8 | 2,656.9 | 3,160.4 | 2,864.7 | 2,235.4 | 895.7 | 160 | |
| 2011 | 298 | 274 | 164.5 | 642.1 | 972.6 | 1,466.0 | 2,676.7 | 3,097.9 | 3,152.9 | 1,984.8 | 944.6 | 194 | |
| 2012 | 284 | 191 | 93.2 | 577.6 | 1,361.6 | 1,939.3 | 2,983.4 | 3,179.8 | 3,042.5 | 1,893.1 | 817.1 | 98 | |
| 2013 | 389 | 227 | 236.3 | 742.4 | 1,259.6 | 1,988.9 | 3,011.1 | 3,126.4 | 3,021.5 | 1,446.6 | 645.1 | 198 | |
| 2014 | 229 | 112 | 323.4 | 614.6 | 1,091.3 | 1,860.5 | 2,793.1 | 3,116.5 | 2,920.6 | 2,050.9 | 1,036.7 | 114 | |
| 2015 | 299 | 76 | 413.4 | 842.7 | 1,089.5 | 1,960.5 | 3,029.5 | 3,136.2 | 3,195.7 | 2,294.2 | 805.3 | 237 | |
| Normals 10-years ending Dec 2015 | 307 | 206 | 206 | 588 | 1,144 | 1,844 | 2,863 | 3,111 | 2,980 | 1,923 | 857 | 163 | |

**Response to Data Request AIC 1.8**

## ARIZONA PUBLIC SERVICE COMPANY
## BILLING MONTH ACTUAL WEATHER--RESIDENTIAL
## YEARS 1996 THROUGH 2005

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Residential HDDs (base 65°)** | | | | | | | | | | | | | |
| 1996 | 301 | 191 | 121 | 21 | NA | NA | NA | NA | NA | NA | 59 | 185 | 878 |
| 1997 | 307 | 229 | 142 | 36 | NA | NA | NA | NA | NA | NA | 32 | 241 | 987 |
| 1998 | 342 | 260 | 232 | 130 | NA | NA | NA | NA | NA | NA | 35 | 208 | 1,207 |
| 1999 | 279 | 224 | 85 | 110 | NA | NA | NA | NA | NA | NA | 3 | 185 | 886 |
| 2000 | 292 | 141 | 150 | 50 | NA | NA | NA | NA | NA | NA | 123 | 217 | 973 |
| 2001 | 283 | 323 | 196 | 57 | NA | NA | NA | NA | NA | NA | 6 | 212 | 1,077 |
| 2002 | 308 | 254 | 98 | 27 | NA | NA | NA | NA | NA | NA | 4 | 127 | 818 |
| 2003 | 256 | 119 | 144 | 31 | NA | NA | NA | NA | NA | NA | 30 | 180 | 760 |
| 2004 | 265 | 272 | 168 | 15 | NA | NA | NA | NA | NA | NA | 45 | 243 | 1,008 |
| 2005 | 270 | 181 | 118 | 31 | NA | NA | NA | NA | NA | NA | 4 | 176 | 780 |
| **Residential CDDs (base 80°)** | | | | | | | | | | | | | |
| 1996 | NA | NA | NA | NA | 81 | 235 | 406 | 431 | 311 | 114 | NA | NA | 1,578 |
| 1997 | NA | NA | NA | NA | 108 | 218 | 353 | 403 | 354 | 178 | NA | NA | 1,614 |
| 1998 | NA | NA | NA | NA | 8 | 71 | 347 | 435 | 379 | 102 | NA | NA | 1,342 |
| 1999 | NA | NA | NA | NA | 12 | 133 | 387 | 343 | 339 | 159 | NA | NA | 1,373 |
| 2000 | NA | NA | NA | NA | 57 | 265 | 369 | 470 | 335 | 209 | NA | NA | 1,705 |
| 2001 | NA | NA | NA | NA | 103 | 310 | 427 | 434 | 419 | 221 | NA | NA | 1,914 |
| 2002 | NA | NA | NA | NA | 37 | 238 | 476 | 457 | 413 | 170 | NA | NA | 1,791 |
| 2003 | NA | NA | NA | NA | 35 | 306 | 466 | 480 | 401 | 241 | NA | NA | 1,929 |
| 2004 | NA | NA | NA | NA | 64 | 199 | 382 | 441 | 348 | 142 | NA | NA | 1,576 |
| 2005 | NA | NA | NA | NA | 29 | 218 | 450 | 418 | 380 | 199 | NA | NA | 1,694 |
| **Humidity** | | | | | | | | | | | | | |
| 1996 | NA | NA | NA | NA | 17.5 | 19.5 | 28.6 | 34.9 | 41.6 | 34.0 | NA | NA | |
| 1997 | NA | NA | NA | NA | 22.5 | 21.9 | 20.0 | 33.6 | 41.7 | 35.7 | NA | NA | |
| 1998 | NA | NA | NA | NA | 30.3 | 24.4 | 28.0 | 36.5 | 37.4 | 30.5 | NA | NA | |
| 1999 | NA | NA | NA | NA | 27.7 | 21.0 | 32.6 | 41.8 | 38.8 | 33.8 | NA | NA | |
| 2000 | NA | NA | NA | NA | 21.3 | 20.0 | 27.4 | 27.1 | 34.7 | 33.4 | NA | NA | |
| 2001 | NA | NA | NA | NA | 25.4 | 18.3 | 25.7 | 35.4 | 30.6 | 28.3 | NA | NA | |
| 2002 | NA | NA | NA | NA | 18.4 | 13.8 | 16.9 | 28.4 | 26.8 | 27.4 | NA | NA | |
| 2003 | NA | NA | NA | NA | 20.6 | 15.0 | 16.5 | 30.5 | 33.9 | 29.9 | NA | NA | |
| 2004 | NA | NA | NA | NA | 18.8 | 14.4 | 16.3 | 28.0 | 27.0 | 26.9 | NA | NA | |
| 2005 | NA | NA | NA | NA | 22.3 | 20.3 | 17.0 | 36.6 | 30.8 | 25.4 | NA | NA | |
| **Weather** | | | | | | | | | | | | | |
| 1996 | 301 | 191 | 121 | 21 | 231.8 | 698.0 | 1,361.5 | 1,531.1 | 1,159.4 | 402.0 | 59 | 185 | |
| 1997 | 307 | 229 | 142 | 36 | 336.3 | 672.9 | 1,057.5 | 1,416.4 | 1,320.6 | 636.4 | 32 | 241 | |
| 1998 | 342 | 260 | 232 | 130 | 27.3 | 226.8 | 1,156.3 | 1,564.8 | 1,372.6 | 348.6 | 35 | 208 | |
| 1999 | 279 | 224 | 85 | 110 | 39.9 | 404.9 | 1,348.4 | 1,280.4 | 1,240.2 | 559.8 | 3 | 185 | |
| 2000 | 292 | 141 | 150 | 50 | 174.3 | 793.9 | 1,221.6 | 1,550.8 | 1,188.2 | 733.3 | 123 | 217 | |
| 2001 | 283 | 323 | 196 | 57 | 333.2 | 901.1 | 1,386.3 | 1,548.0 | 1,433.4 | 738.8 | 6 | 212 | |
| 2002 | 308 | 254 | 98 | 27 | 107.8 | 624.7 | 1,345.8 | 1,529.3 | 1,358.1 | 562.8 | 4 | 127 | |
| 2003 | 256 | 119 | 144 | 31 | 105.9 | 828.7 | 1,306.4 | 1,640.5 | 1,412.9 | 818.9 | 30 | 180 | |
| 2004 | 265 | 272 | 168 | 15 | 187.8 | 530.8 | 1,066.2 | 1,469.5 | 1,147.0 | 467.5 | 45 | 243 | |
| 2005 | 270 | 181 | 118 | 31 | 90.0 | 656.3 | 1,274.9 | 1,504.8 | 1,302.5 | 643.7 | 4 | 176 | |

**Response to Data Request AIC 1.8**

## ARIZONA PUBLIC SERVICE COMPANY
## BILLING MONTH ACTUAL WEATHER–GENERAL SERVICE
## YEARS 1996 THROUGH 2005

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| General Service CDDs (base 65°) | | | | | | | | | | | | | |
| 1996 | NA | NA | 46 | 147 | 449 | 678 | 874 | 876 | 770 | 532 | 152 | NA | 4,524 |
| 1997 | NA | NA | 87 | 179 | 483 | 669 | 811 | 851 | 817 | 553 | 153 | NA | 4,603 |
| 1998 | NA | NA | 18 | 67 | 252 | 474 | 809 | 875 | 826 | 493 | 135 | NA | 3,949 |
| 1999 | NA | NA | 30 | 78 | 249 | 558 | 840 | 782 | 788 | 582 | 333 | NA | 4,240 |
| 2000 | NA | NA | 21 | 147 | 427 | 719 | 824 | 923 | 792 | 615 | 107 | NA | 4,575 |
| 2001 | NA | NA | 23 | 167 | 442 | 768 | 891 | 881 | 863 | 647 | 371 | NA | 5,053 |
| 2002 | NA | NA | 37 | 230 | 380 | 676 | 935 | 899 | 869 | 581 | 207 | NA | 4,814 |
| 2003 | NA | NA | 29 | 118 | 290 | 744 | 925 | 927 | 861 | 689 | 303 | NA | 4,886 |
| 2004 | NA | NA | 88 | 267 | 408 | 653 | 844 | 887 | 802 | 573 | 162 | NA | 4,684 |
| 2005 | NA | NA | 20 | 119 | 314 | 667 | 910 | 862 | 841 | 630 | 265 | NA | 4,628 |
| Humidity | | | | | | | | | | | | | |
| 1996 | NA | NA | 37.5 | 27.4 | 17.5 | 19.5 | 28.6 | 34.9 | 41.6 | 34.0 | 30.6 | NA | |
| 1997 | NA | NA | 36.0 | 30.9 | 22.5 | 21.9 | 20.0 | 33.6 | 41.7 | 35.7 | 34.5 | NA | |
| 1998 | NA | NA | 53.2 | 45.9 | 30.3 | 24.4 | 28.0 | 36.5 | 37.4 | 30.5 | 41.8 | NA | |
| 1999 | NA | NA | 31.1 | 36.7 | 27.7 | 21.0 | 32.6 | 41.8 | 38.8 | 33.8 | 25.3 | NA | |
| 2000 | NA | NA | 40.7 | 33.2 | 21.3 | 20.0 | 27.4 | 27.1 | 34.7 | 33.4 | 54.9 | NA | |
| 2001 | NA | NA | 51.7 | 38.2 | 25.4 | 18.3 | 25.7 | 35.4 | 30.6 | 28.3 | 32.3 | NA | |
| 2002 | NA | NA | 21.7 | 23.7 | 18.4 | 13.8 | 16.9 | 28.4 | 26.8 | 27.4 | 32.9 | NA | |
| 2003 | NA | NA | 49.9 | 28.1 | 20.6 | 15.0 | 16.5 | 30.5 | 33.9 | 29.9 | 32.9 | NA | |
| 2004 | NA | NA | 42.8 | 32.0 | 18.8 | 14.4 | 16.3 | 28.0 | 27.0 | 26.9 | 43.5 | NA | |
| 2005 | NA | NA | 57.5 | 28.6 | 22.3 | 20.3 | 17.0 | 36.6 | 30.8 | 25.4 | 32.1 | NA | |
| Weather | HDDs (base 65°) | HDDs (base 65°) | | | | | | | | | | HDDs (base 65°) | |
| 1996 | 301 | 191 | 166.7 | 486.6 | 1,285.1 | 2,013.9 | 2,930.9 | 3,112.0 | 2,870.6 | 1,876.0 | 520.0 | 185 | |
| 1997 | 307 | 229 | 311.8 | 614.1 | 1,503.8 | 2,064.9 | 2,429.5 | 2,990.9 | 3,047.8 | 1,977.1 | 541.8 | 241 | |
| 1998 | 342 | 260 | 71.5 | 256.4 | 859.6 | 1,514.2 | 2,695.8 | 3,147.6 | 2,991.5 | 1,684.9 | 503.9 | 208 | |
| 1999 | 279 | 224 | 103.1 | 281.0 | 827.0 | 1,698.8 | 2,926.8 | 2,919.1 | 2,882.8 | 2,048.9 | 1,075.9 | 185 | |
| 2000 | 292 | 141 | 77.8 | 514.9 | 1,306.1 | 2,153.9 | 2,727.9 | 3,045.5 | 2,809.0 | 2,157.8 | 428.6 | 217 | |
| 2001 | 283 | 323 | 90.7 | 608.4 | 1,429.8 | 2,232.5 | 2,892.6 | 3,142.3 | 2,952.3 | 2,162.8 | 1,289.2 | 212 | |
| 2002 | 308 | 254 | 113.9 | 728.1 | 1,106.7 | 1,774.3 | 2,643.5 | 3,008.4 | 2,857.6 | 1,923.4 | 723.1 | 127 | |
| 2003 | 256 | 119 | 113.4 | 393.6 | 877.3 | 2,014.8 | 2,593.1 | 3,168.2 | 3,033.7 | 2,341.1 | 1,058.5 | 180 | |
| 2004 | 265 | 272 | 330.6 | 925.4 | 1,197.0 | 1,741.7 | 2,355.7 | 2,955.7 | 2,643.3 | 1,886.4 | 611.2 | 243 | |
| 2005 | 270 | 181 | 81.0 | 399.1 | 974.8 | 2,008.1 | 2,578.2 | 3,103.2 | 2,882.5 | 2,037.9 | 919.2 | 176 | |